IPTC 10330

An Integrated Approach to Waterflood Management in a Palaeozoic, High-Viscosity Oil Reservoir: A Case Study of Haima-West Reservoir in a Mature Field in South Oman

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Abstract

The Haima West reservoir in a mature field in south Oman showed severe production decline after initial encouraging results in re-development phase using horizontal injectors and horizontal producers. This sharp decline was due to rapid short- circuiting of injected water through possible presence of natural open fractures, induced fractures and/or thief zones. Further development of the reservoir was put on hold and an integrated well and reservoir management team was put in place to manage the waterflood with existing well stock and arrest production decline. The case study presents the successful implementation of a reservoir surveillance and optimization plan which could arrest production decline from the reservoir. Extensive data acquisition programme during this phase to reduce uncertainty in the next phase of development is discussed.

Introduction

The field under discussion is located on the Eastern flank of South Oman salt basin **(Fig.1)**. The field comprises a NE-SW trending anticline about 14 km long and 8 km wide. To date, more than 400 wells have been drilled in the field encountering oil producing reservoirs in the Mahwis formation (the Haima group of Cambro-Ordivician age) and the Al Khlata and Gharif formations (Haushi group of Carboniferous/Permian age) at depth ranges of 550-675 m sub-sea (ss). The case history presented in this paper focuses on the western culmination of the Mahwis formation in the field (known as Haima West Reservoir)

The Haima West reservoir crude has high viscocity (90 cp) and moderate to low API gravity (22 deg API oil). The reservoir has been on production since 1980 and currently has about 70 active wells of which 60 are oil producers and 10 are water injectors. The reservoir was initially developed using vertical wells on a 600 m spacing that was later reduced to 425 m spacing by drilling in-fill wells. To arrest rapid pressure decline, water injection using two five-spot patterns commenced in 1997. In 1999, a change in field development plan was initiated. The plan involved drilling of horizontal producers supported by long horizontal injectors. Till 2002 a total of 19 horizontal producers and 6 horizontal injectors were drilled. The initial response of the horizontal well development was encouraging with the first five producers showing significant improvement in productivity over the earlier vertical wells. However, with initiation of water injection rapid short-circuiting was observed between some wells that indicated possible presence of natural open fractures, induced fractures and/or thief zones channeling the water. This resulted in sharp decline in oil production from the reservoir. Further field development was put on hold until further studies could establish the cause of water short-circuiting.

An integrated well and reservoir management team was put in place to effectively manage the waterflood with existing well stock and optimize production from the reservoir. This paper presents how the production decline could be arrested by implementation of a judicious reservoir surveillance plan and optimization of injection rates in individual water injectors.

Reservoir Geology

The majority of the Haima deposits were deposited in Cambro-Ordovician times. The Haima West structure is interpreted as the collapsed crest of an anticline, which was subject to later inversion. Regionally, strike slip movements affected the area.

The Mahwis formation has been divided into twelve zones on the basis of large scale fining upward sequences. All layers are formed by stacked sheet-flood deposits, except for the Intra Haima Marker (IHM), which is a clear shale marker that defines the top of the Lower Mahwis. (**Fig.2** presents a type log showing different zones).

From formation imaging logs run in many wells and fracture analysis from cores, the Haima West reservoir has been interpreted to be mildly fractured. Most fractures are interpreted to be partly closed.

Field Production and Development History

Production from Haima West reservoir commenced in late 1980. The development of the field has been carried out in phases as detailed below:

Initial Development (1981-1983) The field was initially developed using vertical wells on a uniform spacing of 600 m.

Most of the wells were completed with external gravel packs or a combination of external and internal gravel packs for sand control.

Phase-1 In-fill Drilling (1986-87) The infill drilling campaign with vertical producers reduced the average spacing to 425 m.

Phase-2 Infill Drilling (1998-99) and Water Injection Trial: A few wells were drilled in this campaign partly to test different sand exclusion techniques. Due to depleted reservoir reservoir pressure and high skins caused by gravel pack completions, the vertical wells had average production rates of about 15 m^3/d. Due to weak natural water drive, producing gas-oil ratio (GOR) rose rapidly as reservoir pressure declined from initial level of 9300 KPa to 5500 KPa. Three inverted five spot pilot water injectors were completed during this period. The wells showed good injectivity of about 1000 m3/d at 5000 kPa tubing head pressure. A favourable production response was observed in many wells.

Development using horizontal producers and horizontal injectors (1999-2002): Field trials were conducted to confirm the viability of horizontal wells in the apparently low K_v/K_h environment showed encouraging results. A part of the productivity improvement was also due to elimination of down-hole sand exclusion techniques and using co-production of sand as an integral part of the production process. The in-place volumes were revised upwards due to establishment of producible oil in low resistivity pay. A new field development plan was put in place which envisaged full field development using horizontal producers and injectors. Till 2002, a total of 19 horizontal producers and 6 horizontal injectors were drilled. The initial response of the horizontal well development was encouraging with the first five producers showing significant improvement in productivity over the earlier vertical wells. However, with initiation of water injection rapid short-circuiting was observed between some wells that indicated possible presence of natural open fractures, induced fractures and/or thief zones channeling the water. This resulted in sharp decline in oil production from the reservoir. Further field development was put on hold until further studies could establish the cause of water short-circuiting

Data Gathering and Analysis for next phase of development (2002-2005): A few vertical wells were drilled during the period to carry out a controlled 5 spot pilot and collect good core sample to establish the producibility of the low resistivity pay. A duplet water injection pilot comprising a horizontal producer and a horizontal injector was also planned. The primary objective was to perform detailed analysis of all available information and gather additional data before proceeding with the next phase of development.

Fig.3. shows the performance of the Haima West Reservoir.

Waterflood Management Challenges

During implementation of the 1999 field development plan using horizontal producers and horizontal injectors, the oil production from the reservoir had reached a level of about 2000 m^3/d by beginning of 2001 from 750 m^3/d in beginning of 1999. However, production from the reservoir declined very fast with early breakthrough of water in producers and had declined to a level of 1200 m^3/d by end of 2002 when the field development plan was halted.

The primary challenge for the well and reservoir management team was to effectively manage the waterflood with existing well stock and optimize production from the reservoir. Additionally, the team was given the responsibility of carrying out an effective data gathering campaign to mitigate the risk of future field development. These are discussed in further detail below:

Identifying Injection Patterns in the Reservoir

Effective management of a waterflood requires identification of the interaction between the injectors and producers so that the performance of each pattern can be analyzed. This, in the case of Haima West reservoir, proved to be a formidable challenge for the following reasons:

- The reservoir was initially developed using vertical wells and many of them were completed in multiple zones. In some of the wells even Lower and Upper Haima are commingled.
- A number of wells were producing at moderate levels of water cut at the beginning of waterflood.
- Most of the earlier vertical wells were completed with external gravel packs and all the wells were completed with either bean pump or screw pumps. This made production logging surveys in producers impossible.
- A combination of vertical and horizontal wells in the reservoir made pattern identification very difficult. The line drive waterflood with horizontal injectors and producers envisaged the reservoir to be waterflooded with a 250 m lateral producer-to-injector spacing. The injectors were designed to be longer than the producers so that each injector can support more than one producer. A schematic diagram of waterflood scheme is shown in **Fig. 4.** The vertical offset between the producers and injectors was about 50 m. The communication path between injectors and producers is often due to short-circuiting through either pre-existing open fractures or induced fractures because of injection at high rates. Thus, an injector might communicate with a producer situated far away but might not communicate with a well situated in its immediate vicinity.
- There were some additional uncertainties introduced because there was a change in the testing device to measure fluid production rates. Historically well tests were carried out using test separators. In mid-2003 test separators were replaced with multi-phase meters for well testing. There was some teething problems related to calibration of the multi-phase meter during the initial phase. This resulted in some uncertainties in both gross liquid rate and water cut.

Despite these difficulties, an attempt was made to closely observe the response of the producers to each of the injectors in the field to arrive at an injection pattern scheme. The Operational team and Petroleum Engineering team together worked out a detailed well testing program. The testing programme prioritized the wells which need to be tested and also the frequency of tests in individual wells. The frequency of test in a well was based on the production rate of individual well and the likelihood of the well being impacted by water injection. To minimize the uncertainty in water cut measurement, the water cut calculated from multiphase meters were checked for consistency with that of well-head samples. Tests showing inconsistent results were discarded. The production parameters (gross liquid rate, oil rate, water cut) of all the producers in the vicinity of an injector were plotted along with the injection rate of the injector to look for any relationship. Care was taken to record all possible well intervention and optimization activities in the producer so as to ensure that the change in production behaviour of a well is due to injection response alone and not any other extraneous factors.

The above procedure is illustrated by means of an example below.

Inj-A Water Injection Pattern

INJ-A, a horizontal water injector was primarily meant to support two horizontal producers **PROD-A** and **PROD-B.** However, the water injected in Inj-A could potentially support more wells in its vicinity. **Fig. 5** shows the wells in the neighbourhood of **INJ-A**. For the purpose of analysis, the response of a number of wells to water injection in **INJ-A** was examined.

In **PROD-A** (please refer to **Fig. 6a**), both total liquid rate and water cut showed a sharp increase as soon as water injection was initiated at high rate (between 1200 – 2000 m^3/d). However, the impact of water injection at high rate resulted in short-circuiting through either open or induced fractures and the sharp rise in water cut resulted in decline in net oil rate. When the water injection in **INJ-A** was reduced, water cut gradually came down. This clearly shows direct communication between the injector and producer.

In **PROD-B**, the other horizontal producer, the response is more subtle (Please refer to **Fig. 6b**). There was no immediate increase in water cut. It appears that at high injection rates all the injected water was preferentially moving towards **PROD-A**. However, water broke through in the well about 2 years after initiation of water injection in **INJ-A**. Thereafter, water cut increased sharply. When injection in **INJ-A** was suspended for a short period in early 2002, the water cut in **PROD-B** came down for a while. This clearly established hydraulic communication between **PROD-B** and **INJ-A**.

The vertical wells **PROD-C** and **PROD-D** are part of the 5 spot pattern and supported by the vertical injector **INJ-B** (Please refer to **Fig. 5**). However, both these wells have been strongly impacted by **INJ-A** water injector as can be seen from **Fig. 7(a)** and **Fig. 7(b)**. Both liquid rate and water cut increased pronouncedly once water injection commenced in **INJ-A**. Water cut in both these wells came down once water injection in **INJ-A** was reduced. This clearly establishes that both **PROD-C** and **PROD-D** are in hydraulic communication with **INJ-A** water injector.

For the horizontal producer **PROD-E** and vertical producer **PROD-F**, the hydraulic communication with **INJ-A** injector has not been conclusively established. **PROD-E** has not been on regular production due to repeated pump failure on account of sand production. **PROD-F** was already producing with very high water cut when water injection in **INJ-A** started. Moreover, the well is completed both in Lower and Upper Mahwis and lot of water may be coming in from Lower Mahwis.

From the above analysis, it could be established that the wells **PROD-A**, **PROD-B**, **PROD-C** and **PROD-D** belong to **INJ-A** water injection pattern. Additionally, **PROD-C** and **PROD-D** belong to the **INJ-B** vertical injection pattern as well.

Similar exercise was carried out with all the injectors in the reservoir to establish their pattern response.

Optimization of water Injection rates in individual wells for Pattern Optimization

The water injection rates in the horizontal wells were initially kept at very high levels (in the order of 1500 to 2000 m^3/d). This was done to achieve voidage replacement through a few injectors only. However, this proved to be counter-productive as the advantage of voidage replacement was more than offset by severe reduction of sweep efficiency due to short-circuiting of injected waters to nearby producers through pre-existing as well as induced fractures. The producers that got connected to the injector through such highly conductive path showed sharp increase in water cut and in almost all cases net decline in oil rate. However, other wells in the same pattern that were not connected by fractures appeared to be benefiting from water injection.

The optimization of pattern performance had two criteria:

i. The maximum rate permissible for a water injector was fixed at a rate at which injection will occur at matrix or under existing fracture conditions without facilitating growth of existing fractures or creating induced fractures. This rate was deduced from plot of injection rate and well-head injection pressure and Hall's plot for individual injectors. The well-head injection pressure at which induced fractures were created was found to be consistent with geomechanical measurements carried out in core samples.

ii. Within the upper bound of injection rate as determined from the previous step, the injection rates of injectors were adjusted to provide best pattern performance. It was understood, because of presence of directional conductive flow paths, it was not possible to optimize production on an individual well basis but only on basis of patterns.

The above methodology is illustrated in detail with respect to **INJ-A** pattern below.

Optimization of Water Injection rate in INJ-A

Fig.8 shows the Hall plot (Reference 4) for **INJ-A**. The Hall plot shows that following the initial fill-up period, there is a clear straight line trend for a long interval of time (till about 800000 m^3 of cumulative water injected). This corresponds to either pure matrix injection or fracture injection through pre-existing fracture or induced fracture created during initial period of high water injection rate. It has not been possible to carry out a production logging survey in this well to establish the injection profile and find out the distribution of injected water along the horizontal drain hole. However, based on production logging survey carried out in a number of injectors both horizontal and vertical, it is more likely that injection during the linear portion of the Hall plot corresponds to injection through existing fractures without causing additional fracture growth rather than pure matrix injection. Following this linear trend in Hall plot, there is a short period of high water injection rate (about 1500 m^3/d). The Hall Plot shows a falttening trend during that period. The Hall Plot continued its flat trend when injection rate was subsequently reduced to 200 m^3/d as the well was taking water at zero well-head injection pressure. This clearly indicates that injection at high rate for a short period has definitely resulted in creation of additional fracture.

Fig. 9 shows a plot of well-head injection pressure versus water injection rate. There is a wide scatter of data as the data corresponds to the entire injection history. However, from the plot it is apparent that till a limit of 4500 kPa well-head injection pressure corresponding to a rate of 700 m^3/d, it is possible to inject water without causing additional fracture growth.

Within this upper bound of water injection rate as deduced above, the water injection rate is tuned to optimize pattern performance. The objective is to optimize the performance of the pattern as a whole as in most cases it is impossible to optimize the performance of each and every well in the pattern. An increase in injection rate may improve the performance of a well in the pattern by virtue of better voidage replacement but might adversely impact the performance of another well by short-circuiting and reducing sweep efficiency. Current understanding is that at high injection bottom-hole pressure (e.g., injection at high rates) the fracture break-down gradient gets exceeded and fracturing and/or reactivation of existing fractures occurs. This can lead to short circuiting of water between injector and surrounding producers.

Fig.10 illustrates that an injection rate of about 300 m^3/d results an optimum performance for **INJ-A** injection pattern as it results in maximizing oil production with a stabilized water cut.

The water injection rates of injectors in each pattern were adjusted along the same lines to optimize the waterflood performance of the reservoir as a whole.

Production optimization using information from down-hole pressure gauges

Most of the new horizontal wells drilled were completed with either surface driven progressive cavity pumps (PCP) or sub-surface motor driven progressive cavity pumps (ESPCP). Many of these wells were completed with permanent bottom-hole gauges for monitoring of flowing pressure data. The choice of the artificial lift method was governed primarily by the ability to handle sand production. The old vertical wells which were gravel packed were mostly completed with rod-pumps.

The readings from the bottom-hole gauges are available on real time via supervisory control and data acquisition (SCADA) system. Monitoring of data from these gauges has helped in optimization of production from the reservoir. Capturing the benefit from a waterflood project requires constant optimization of outflow performance of individual wells (by beaning up, speeding up pumps, up-sizing pump capacity, replacing tubing with one of larger diameter etc.) as the inflow of the well shows improvement due to gradual rise in reservoir pressure. This can be achieved very efficiently if bottom-hole pressure of a well can be monitored from bottom-hole gauges.

Fig.11 illustrates how the intake pressure of the pump can be gradually lowered by speeding up the pump in steps so as maximize well production without having an adverse impact on pump performance. In some cases, optimizing the performance of the well may require well intervention to upsize the pump. Reference 5 explains in detail how the performance of pumps can be optimized to achieve twin objectives of maximizing run life while optimizing production.

Improvement in Reservoir Performance

Putting together an integrated reservoir management team in place facilitated effective surveillance of the waterflood and improvement in the performance of the reservoir. A detailed surveillance programme was drawn-up. This included measurement and validation of quality production and injection data, gathering of static bottom hole pressure information, production logging and pressure fall of surveys in injectors, tracer surveys etc. The performance of each well, each pattern and the reservoir as a whole was regularly reviewed by the integrated team. Any optimization opportunity identified in such reviews was implemented as early as practicable.

The improved performance of the reservoir as a manifestation of these efforts is clearly brought out in **Fig.12.** The sharp decline in production during the period 2001-2002 following short-circuiting of injected water into producers could be entirely reversed. In fact the production from the reservoir increased during 2003 because of decline in water cut in individual wells as each pattern in the field was optimized. The production decline observed from 2004 is gentler as compared to the previous trend and is inevitable due to gradual increase in water cut and inadequate voidage replacement using the existing injectors.

Data Acquisition

In addition to optimizing production from the existing well stock as detailed above, the team embarked on detailed data acquisition program to minimise uncertainties of future waterflood development. Some of the major data acquisition programs implemented during this phase are discussed below:

Tracer Surveys in horizontal injectors

Chemical tracer surveys help define often complex injection water flow paths in waterflood operations. Chemical tracer surveys were carried out in two horizontal wells using two different chemicals. In the first injector trisodium phosphate diluted in fresh water was used while in the second injector sodium fluorescein diluted in fresh water was used. Presence and concentration of tracers in produced water from nearby producers or other producers that could be influenced by injection were measured. The arrival times and concentrations of tracers at different producers revealed a lot of information about fluid flow paths in the reservoir.

In the case of first injector **(INJ-C**), practically the entire tracer was detected in another horizontal well (**PROD-G**) within a very short period of time. Rapid arrival of tracer at very high concentration showed very strong hydrodynamic communication between the injector and the producer through an abnormally high conductive path (fracture). This is indicative of very poor sweep efficiency.

In the case of the second injector **(INJ-D**), no such high communication path was detected and tracer was observed in a number of producers, some far way from the injection well.

The performance of the wells in these two patterns is in conformance with the results obtained from tracer test.

Production Logging Survey in Injectors

Production logging survey in memory mode was attempted in most of the injectors. In some of the horizontal injectors, the survey could not be carried out due to operational problems like inability to negotiate significant length of the hole with coiled tubing. However, in all wells where production logging survey could be carried out successfully, it was found that most of the injected water is being taken by only one set of perforation intervals. Thus, long injection wells that were supposed to inject uniformly across a long interval and support a number of producers, were injecting like a “point source” – not much different from that of a vertical injector.

Fig.13 shows the results of production logging survey carried out in one of the long horizontal water injectors **(INJ-D)**. As is evident from the figure, practically the entire injected water is going into the perforated interval Z6. Analysis of formation imaging log clearly indicates that this interval has maximum density of fractures.

These observations, along with the observed short circuiting of water through horizontal injectors due to induced fractures, posed a big question on the effectiveness of horizontal injectors and producers in Haima West. It was realized that the voidage replacement through a few horizontal injectors do not serve any purpose as the sweep efficiency is severely reduced due to short circuiting.

Haima West Water Injection Pilot

In order to have a better understanding of waterflooding in Haima West, two pilot water injection projects were initiated in 2002. One of the pilots was a vertical inverted 5-spot (i.e. one central injector with four oil producers) and the other was a duplet pilot (i.e. two horizontal wells, one producer and one injector). The objectives of the pilots were to assess the impact of injection rate and water quality on injectivity under matrix and fracture conditions, monitor fracture growth (including size and orientation) from pressure transient tests and microseismicity. The operational details of the pilot project are available in Reference 6. The main inferences drawn from the pilot are:

i. Even at very low injection rates (less than 100 m3/d); most of the injected water selectively enters one of the perforation intervals. This corresponds to the one with maximum fracture intensity. Thus, it is not feasible to have injection under classical matrix conditions in Haima West.
ii. Water Injection at relatively low rates (less than 300 m3/d) so as to manage growth of induced fractures results in improvement in waterflood performance.
iii. Installation of especial water cleaning facility is not critical for Haima West waterflood. The normal injection of treated produced water does not pose significant problems.

The Way Forward

The efforts of the Reservoir Management team was complemented by a Reservoir Studies team which carried out a detailed study integrating all the additional data gathered during the period 2002-2004. The results of the study supported the observations of the reservoir management team that pattern water injection using vertical wells will be the preferred option for field development.

Conclusions and Learning Points

The main conclusions and learning points from the case study can be summarized as follows:

I. The sharp production decline trend in the Haima West reservoir could be reversed by effective reservoir management. Additionally, essential data for the next phase of development could be gathered.
II. An effective reservoir surveillance strategy with the help of a multi-disciplinary team is essential for success of a waterflood. Monitoring of injection rates and production behaviour of the wells as frequently as practicable is necessary to facilitate optimization of injection and offtake to optimize pattern performance.
III. It is preferable to go through a detailed pilot phase before implementing any drastically new development plan. The full fledged developing Haima West reservoir using horizontal producers and injectors should have followed a period of pilot to test the concept in greater detail. This could have mitigated the risks associated with the new concept.
IV. Waterfloods may not perform in accordance to expectations. Deviations occur because complexity of the reservoir. Especially, the presence of communicating conductive paths through faults and fractures can only be ascertained conclusively once water is injected into wells.

SI Metric Conversion Factors

ft×3.048 E-01	= m
psi×6.894757 E+00	= kPa
bbl×1.589873 E-01	= m^3
scf/bbl × 1.801175 E-0	= sm^3/m^3
acre × 4.046856 E+03	= m^2

Acnowledgements

The authors would like to acknowledge the contributions of team members Jan Saeby and Abdullah Reesi (Petroleum Development, Oman). Thanks are also due to Dave Pritchard (Shell-Aberdeen) and Hans-Petter Bjoerndal (Shell-Netherland) who were involved with the Haima West study team. The authors are grateful to Diederik Boersma, Project leader of the Waterflood Management Team in Marmul for his encouragement and support. Finally, the authors would like to thank the Management of Petroleum Development Oman and Sultanate of Oman's Ministry of Oil&Gas (MOG) for their kind permission to publish the paper.

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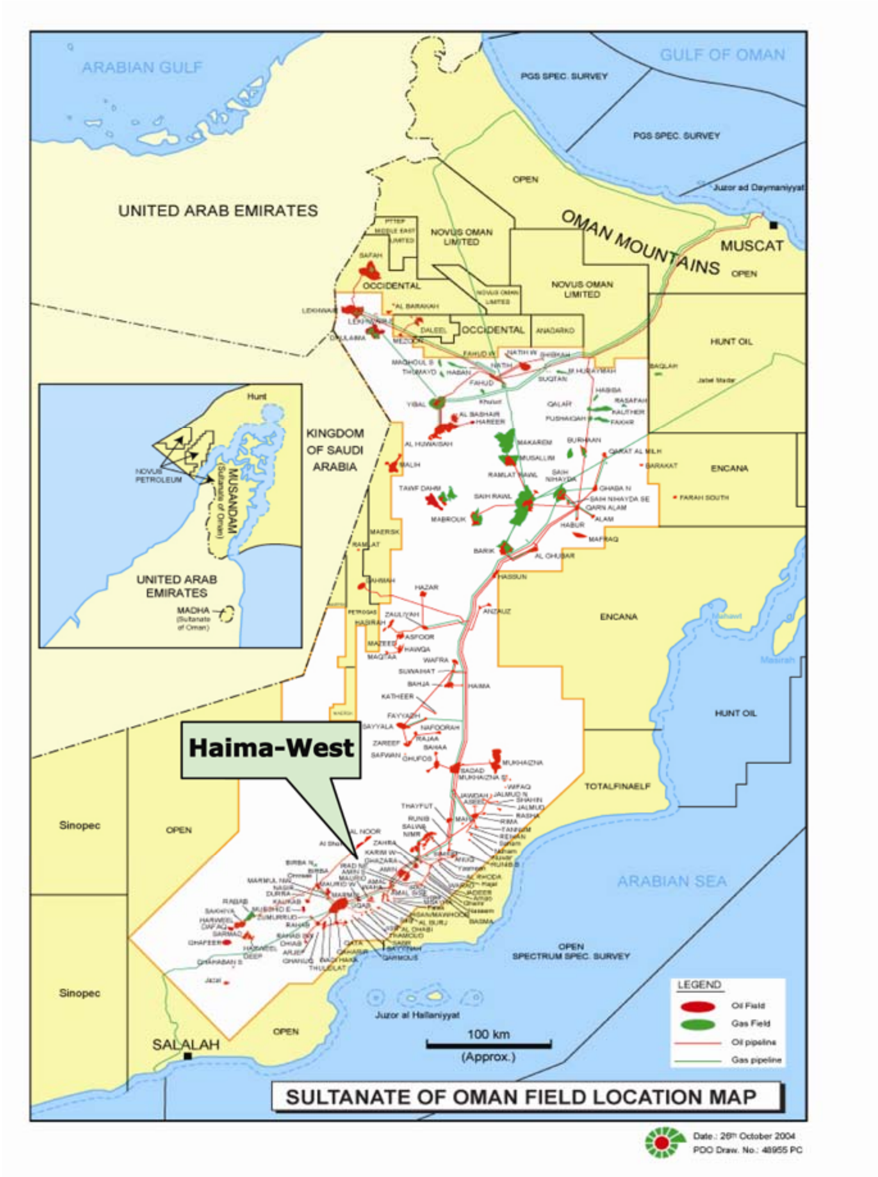

Fig. 1- Location map of Haima West Reservoir

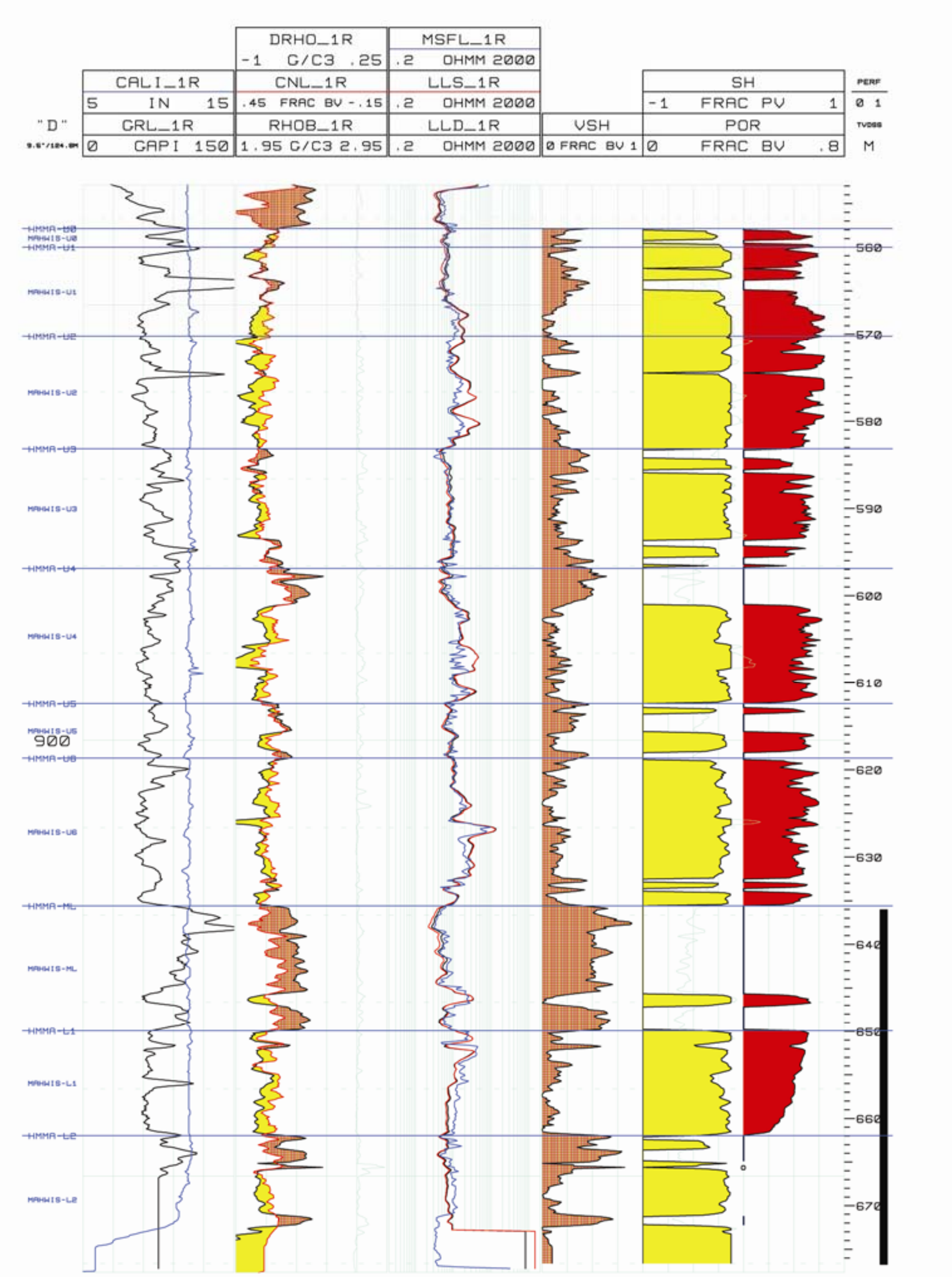

Fig. 2-: Haima West type log showing the different zones

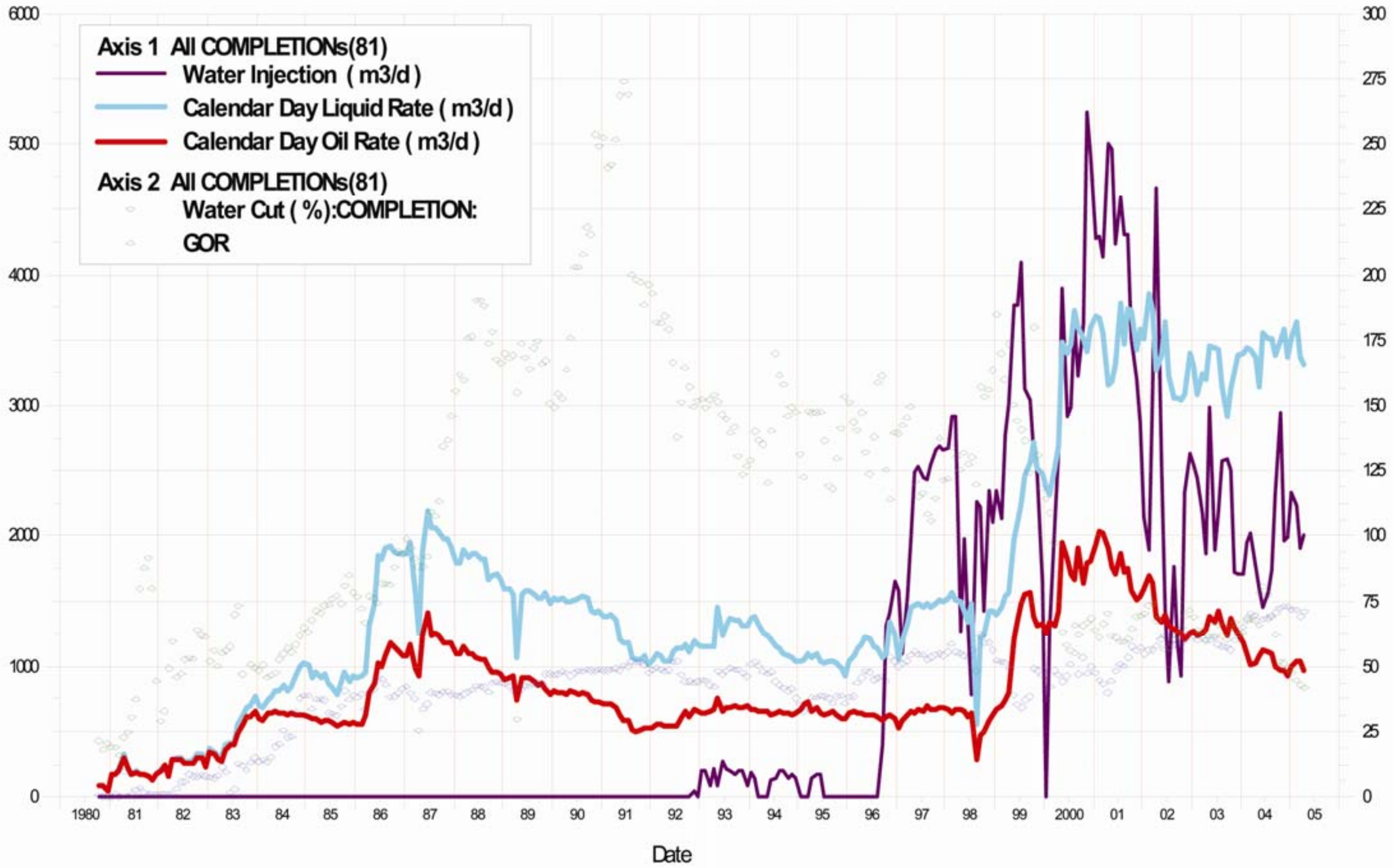

Fig. 3 – Reservoir Performance of Haima West Reservoir. The performance of the field in various phases of development is clearly brought out. Of particular interest is the sharp rise in production during 1999-2000 from drilling horizontal wells and subsequent steep fall during 2001-2002 from short-circuiting of injected water.

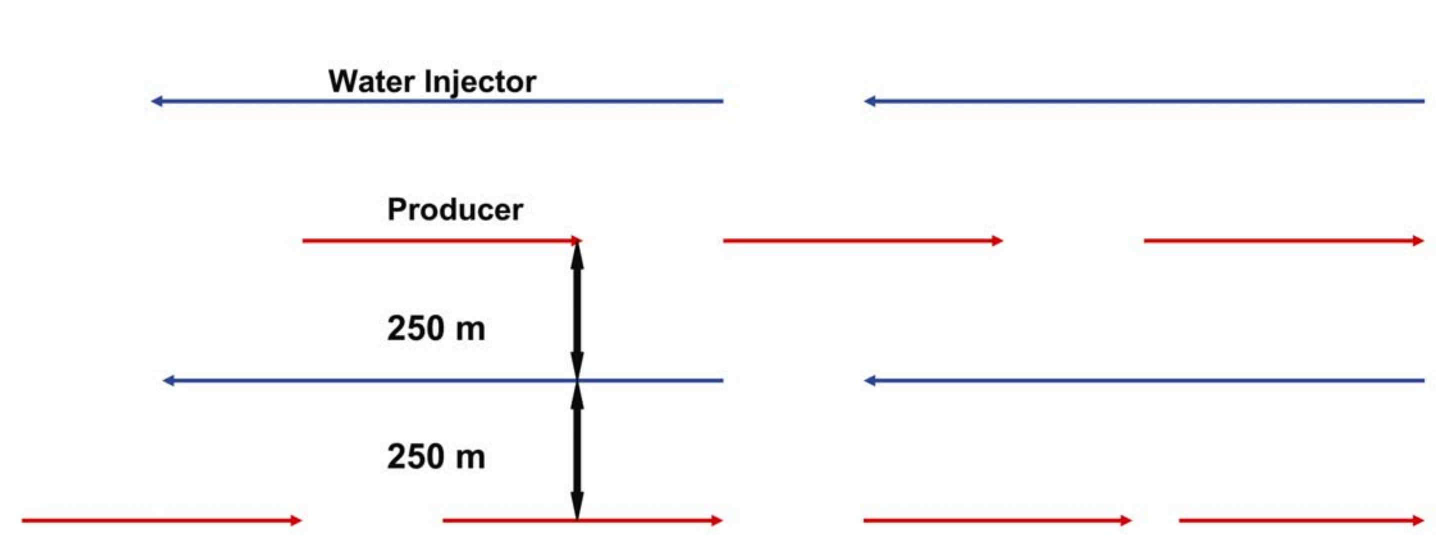

Fig 4. Schematic Plan View of Haima West Waterflood development using horizontal injectors and horizontal producers. The injectors are longer than the producers so that each injector can support more than one producer.

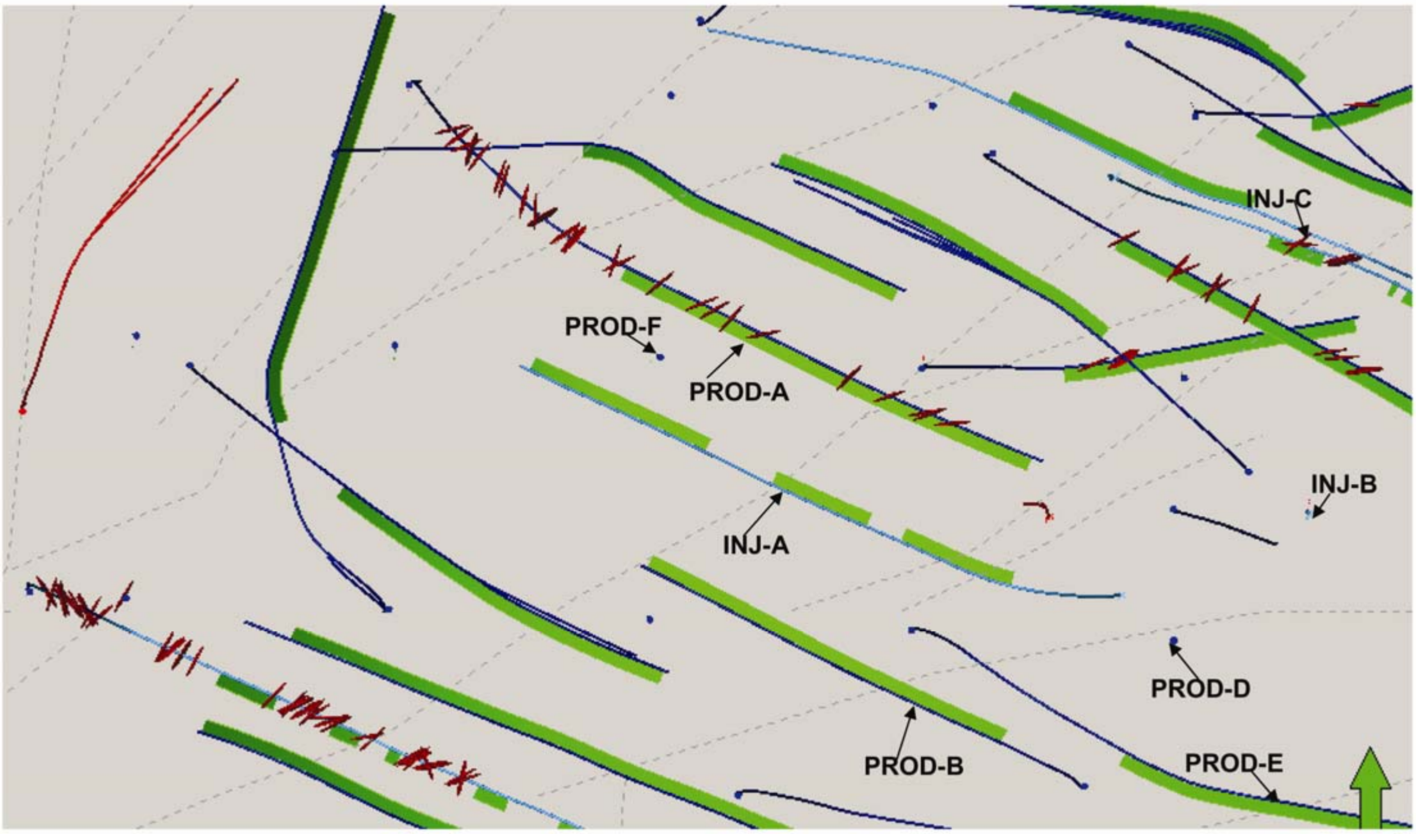

Fig. 5- Water Injection pattern display. Red disks are faults from formation imaging log, green area's highlight perforated intervals. Dashed grey lines show faults.

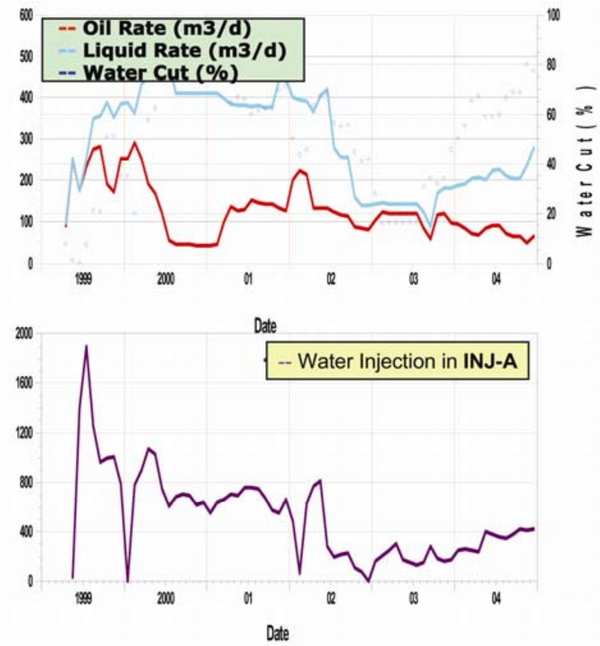

Fig. 6(a) Response in horizontal well **PROD-A** due to injection in **INJ-A.** The response is almost instantaneous. Water cut shoots up very fast which reduces once injection rate in **INJ-A** is reduced.

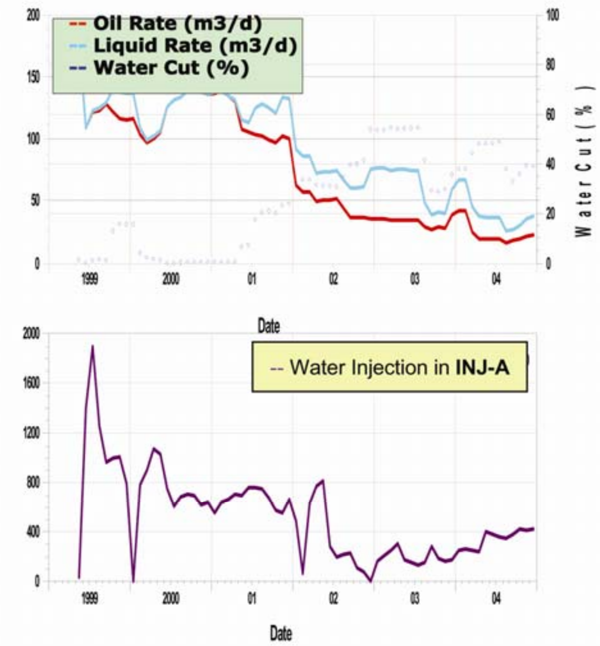

Fig. 6(b) Response in horizontal well **PROD-B** due to injection in **INJ-A**. The response is not as pronounced as in **PROD-A**. Water cut rises gradually and there is a delayed response.

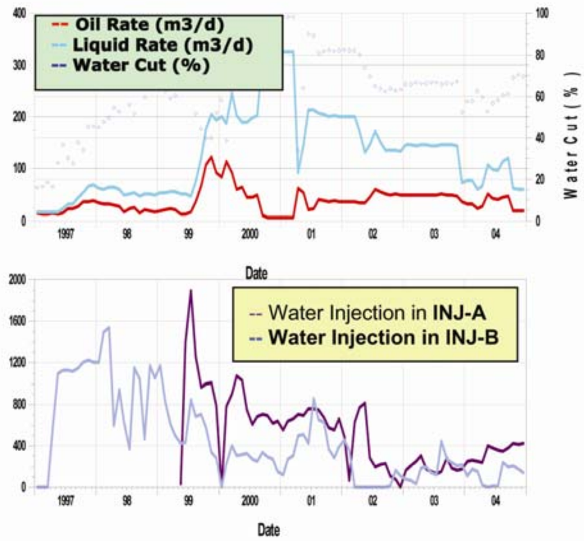

Fig. 7(a) Response in vertical well **PROD-C** due to injection in **INJ-A**. The producer shows response to vertical injector INJ-B as well. But the response from **INJ-A** injector is more prominent. Water cut shoots up very fast which reduces once injection rate in **INJ-A** is reduced.

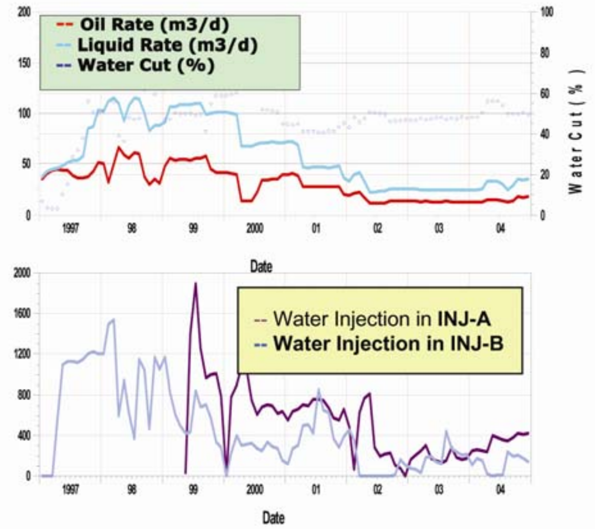

Fig. 7(b) Response in vertical well **PROD-D** due to injection in **INJ-A**. The producer shows response to vertical injector **INJ-B** as well. But the response from **INJ-A** injector is more Water cut shoots up very fast which reduces once injection rate in **INJ-A** is reduced.

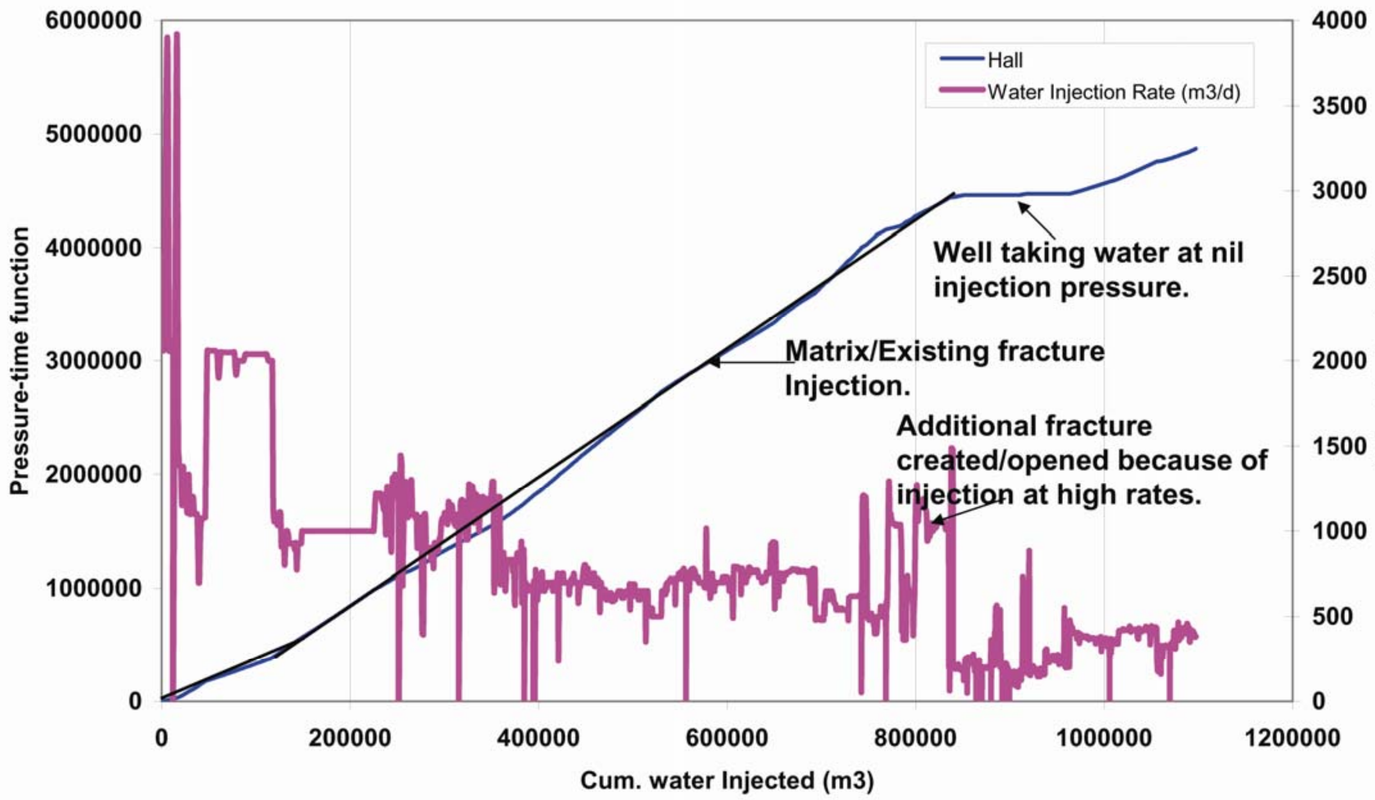

Fig.8- Hall Plot for **INJ-A** carried out on the basis of well head injection pressure and water injection rate. The plot illustrates that injection is mostly being carried out either under matrix or existing fracture conditions most of the time. Creation of additional fracture is indicated immediately after injecting at high rates.

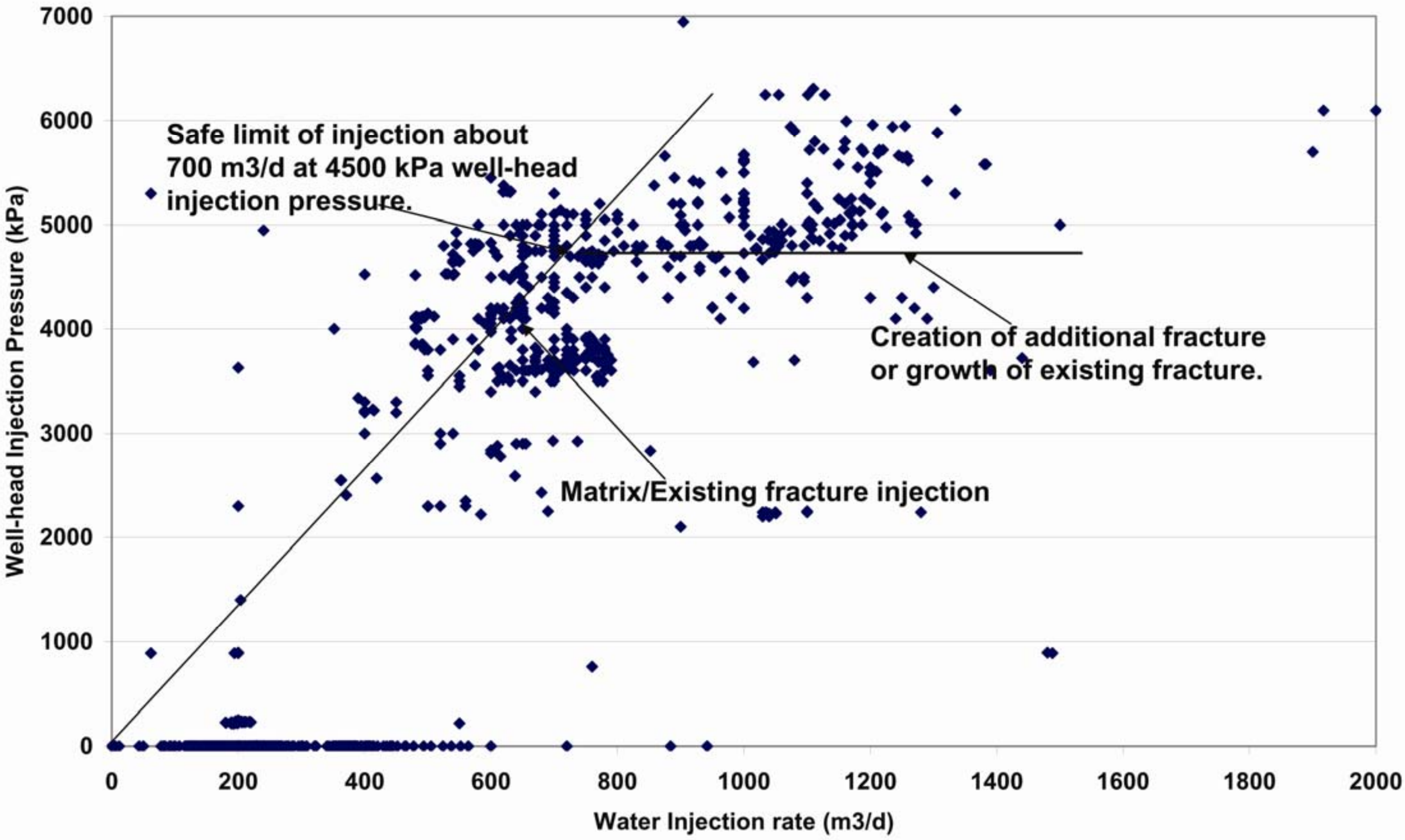

Fig. 9- Plot of well-head injection pressure versus water injection rate indicates the limiting condition to which water can be injected to maintain matrix or existing fracture injection conditions.

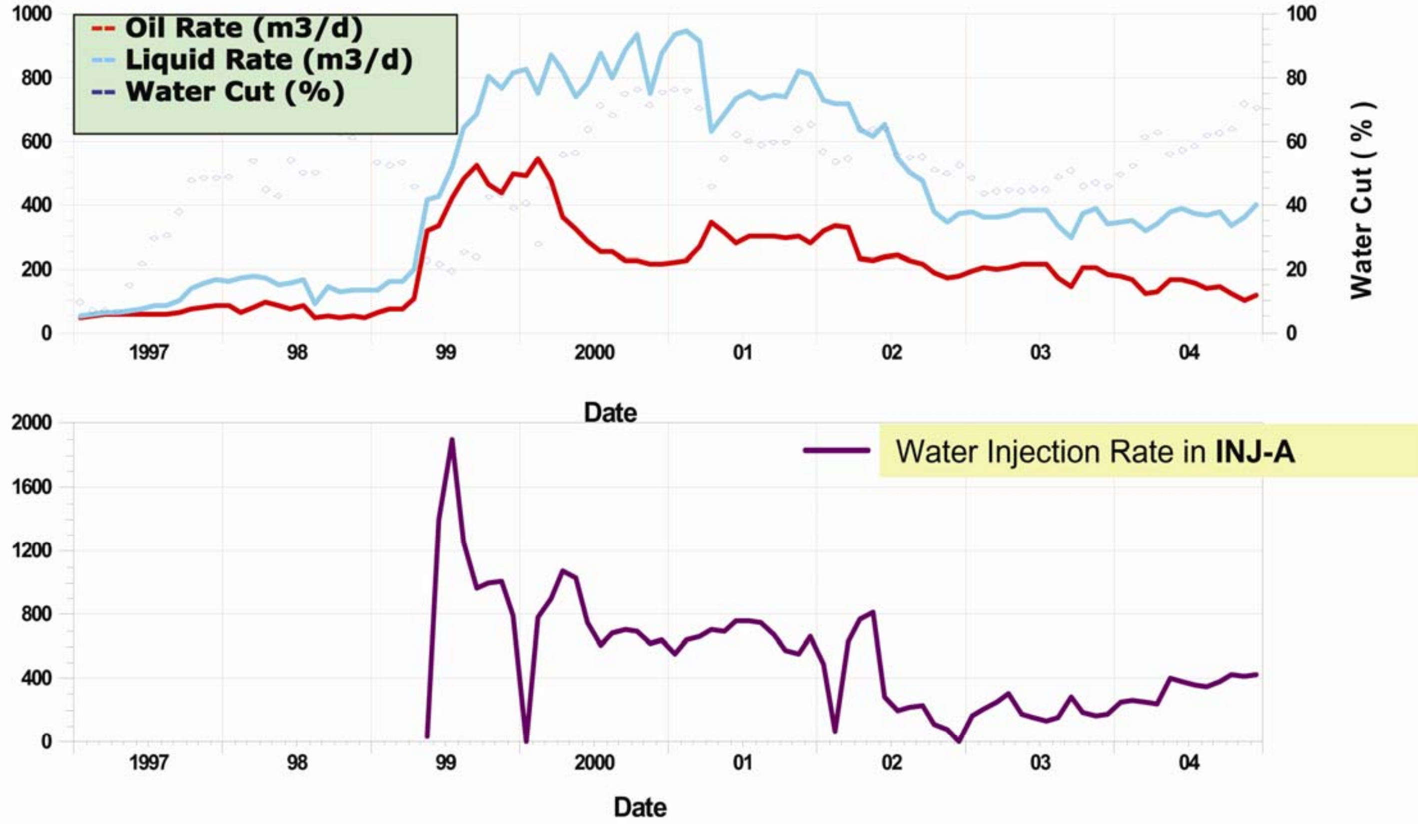

Fig 10: Performance for **INJ-A** pattern. The fact that the production decline could be reversed by reducing water injection rate in **INJ-A** is clearly illustrated.

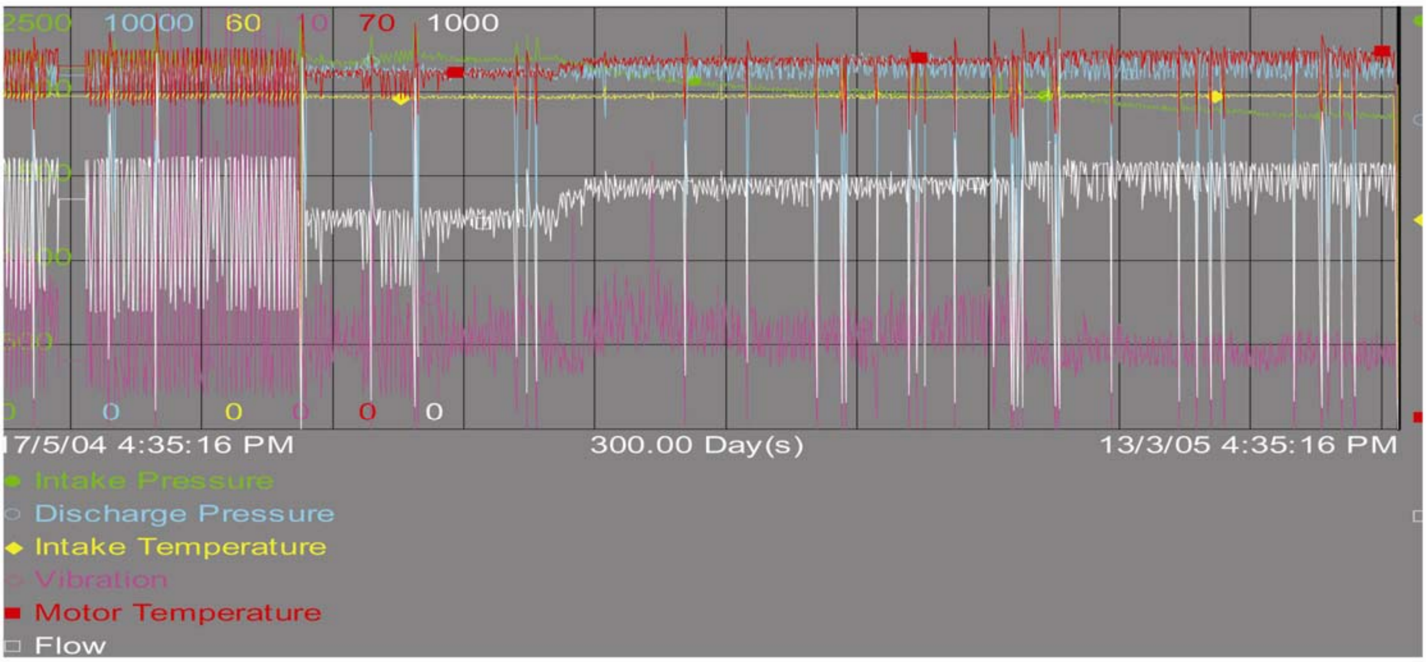

Fig.11- SCADA output of pump performance from one of the horizontal producers equipped with sub-surface motor driven srew pump. Monitoring of the pump parameters facilitates optimization of waterflood performance.

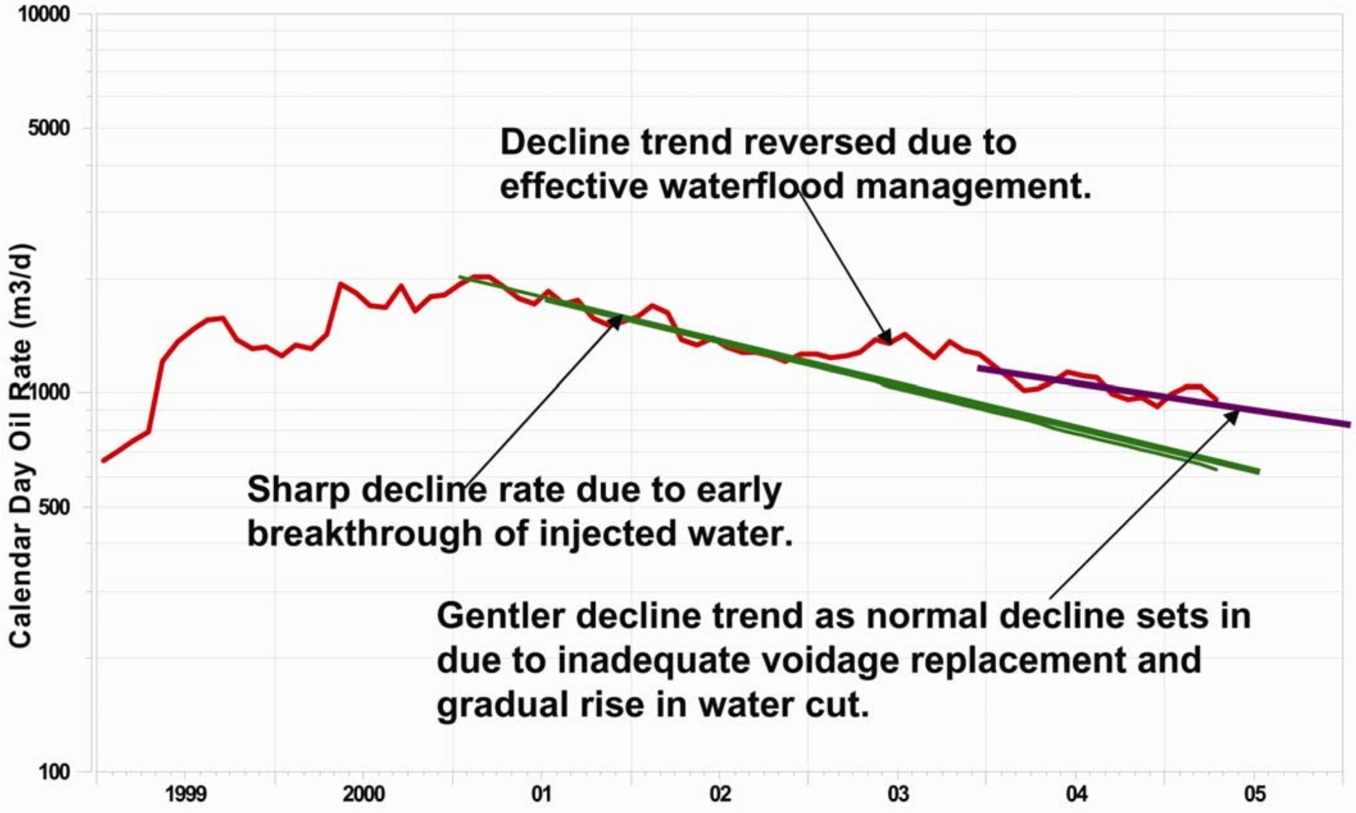

Fig.12- Decline during various phases after development using horizontal wells. Reversing of decline trend followed by a gentler decline trend due to effective waterflood management is illustrated.

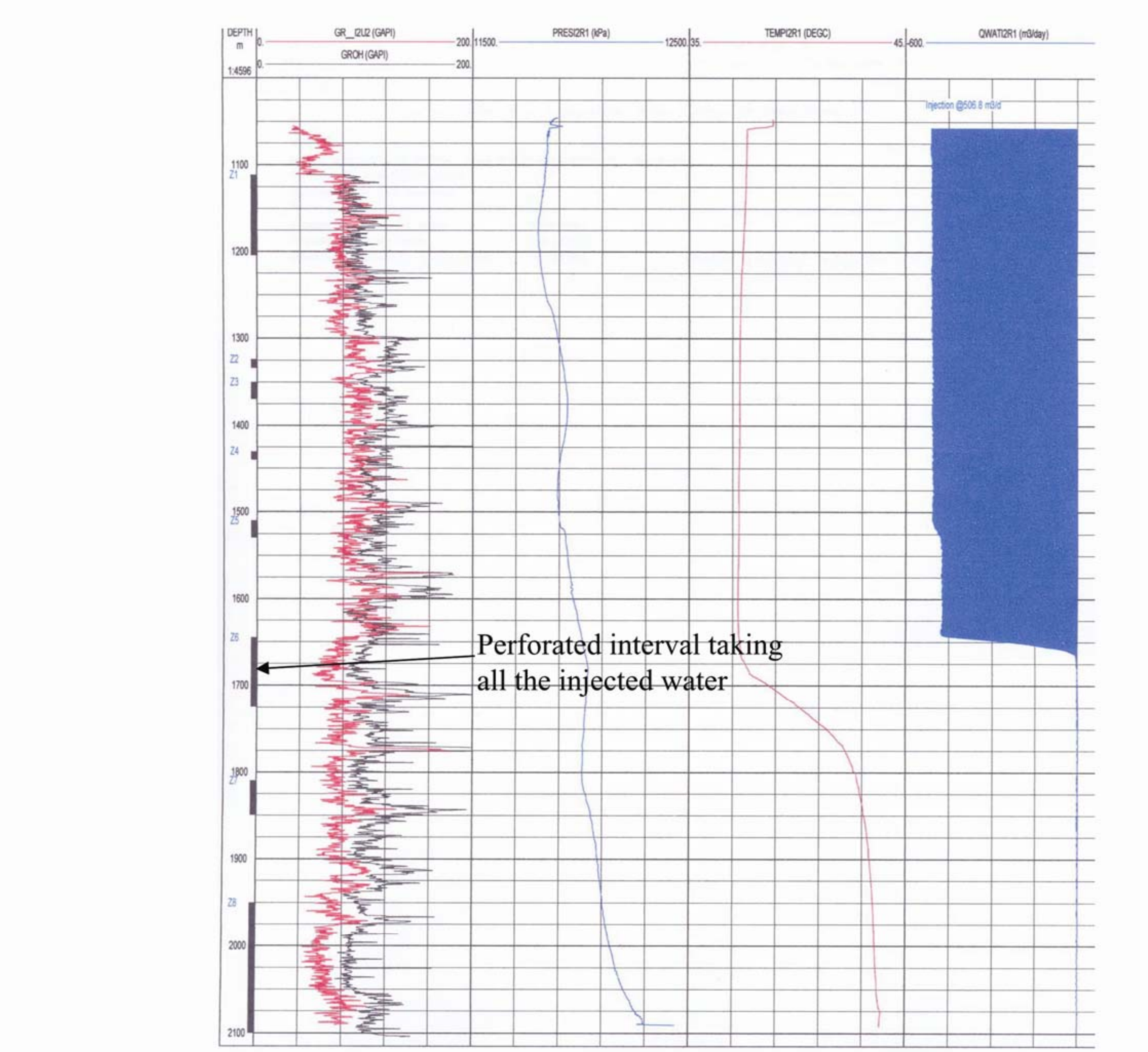

Fig.13- Production logging survey in **INJ-D** clearly indicates that the entire injected water is entering the horizontal well through only one set of perforations.